SURREBUTTAL TESTIMONY AND EXHIBIT

PHILIP HAYET

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NO. 2019-224-E

DOCKET NO. 2019-225-E

IN RE: SOUTH CAROLINA ENERGY FREEDOM ACT (HOUSE BILL 3659) PROCEEDING RELATED TO S.C. CODE ANN. SECTION 58-37-40 AND INTEGRATED RESOURCE PLANS FOR DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND OCCUPATION.

A. My name is Philip Hayet and I am a Vice President and Principal of J. Kennedy and Associates, Inc. ("Kennedy and Associates"). My business address is 570 Colonial Park Drive, Suite 305, Roswell, Georgia, 30075.

Q. DID YOU PREVIOUSLY FILE DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I filed Direct Testimony and one (1) exhibit on behalf of the South Carolina Office of Regulatory Staff ("ORS") on February 5, 2021. I also filed Revised Direct Testimony and one (1) exhibit on March 4, 2021. My Revised Direct Testimony supported portions of the two ORS reports entitled, "Review of Duke Energy Carolinas, LLC 2020 Integrated Resource Plan" (the "DEC Report"), and "Review of Duke Energy Progress, LLC 2020 Integrated Resource Plan" (the "DEP Report") that Kennedy and Associates assisted ORS to prepare.[1] Collectively, the two reports will be referred to as the ORS Reports. Kennedy and Associates' review of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") (collectively "Duke Energy" or the "Companies") 2020 IRPs, included an assessment of the Companies' compliance with the statutory requirements of S.C. Code Ann. Section 58-37-40 ("Section 40"), as amended by the South Carolina Energy Freedom Act ("Act 62").

Q. WHAT WERE YOUR PRIMARY RESPONSIBILITIES WITH REGARD TO THE ORS REPORTS?

A. I had the primary responsibility at Kennedy and Associates for developing the following sections of the ORS Reports:

- Evolution of the IRP Process in South Carolina[2]
- Compliance with Certain Requirements of Section 40
- Energy Efficiency and Demand Side Management
- Natural Gas Price Forecasts
- CO_2 and Other Environmental Issues
- Existing System Resources
- Generic Resource Options
- Renewables
- Transmission System Planning and Investment
- Distribution Resource and Integrated System Operations Plans
- Other Considerations

[1] Copies of the two reports were attached to ORS witness Anthony Sandonato's Direct Testimony as Exhibits AMS-1 and AMS-2.
[2] Mr. Sandonato, with ORS, contributed significantly to the development of this section.

Q. WHAT IS THE PURPOSE OF YOUR SURREBUTTAL TESTIMONY?

A. I respond to the Rebuttal Testimonies of Duke Energy witnesses Snider, Kalemba, and Bak. As part of my testimony, I present an overview of all of the recommendations that ORS identified and discussed in the ORS Reports, and I provide the current status of ORS's position regarding the recommendations. In addition, to the extent that issues with the ORS recommendations are still in dispute or require additional clarification, I indicate which ORS witness will address the issue in more detail in their respective Surrebuttal Testimonies. Finally, I address certain issues that I was responsible for that were discussed in the ORS Reports. ORS witnesses Sandonato, Baron and Kollen describe their responsibilities in their respective Surrebuttal Testimonies.

Q. PLEASE SUMMARIZE ORS'S OVERALL ASSESSMENT OF THE COMPANIES' IRP REPORTS.

A. In Direct Testimony, ORS witnesses Kollen, Baron, and I found that the Companies complied with the informational requirements identified in Sections 40(B)(1) and 40(B)(2). However, we found that there are improvements that could be made to the Companies IRPs related to data assumptions and modeling methodologies. Specifically, my testimony states that "the IRPs would benefit from more detailed information in technical appendices and additional sensitivities to be evaluated. This information may be useful to the Commission as it considers whether the DEC and DEP IRPs balance the seven factors found in Section 40(C)(1)."[3] In total, ORS presented twenty-six (26) recommendations,[4] which the

[3] Hayet Direct Testimony, p. 4, l. 16.
[4] The recommendations found in the tables that ORS presented in Direct Testimony, example see my Direct Testimony at pp. 5 – 10, only included 25 recommendations. ORS actually had a 26th recommendation (Kollen Direct Testimony at p. 11), but it was not previously assigned a recommendation number in the tables. It is now Recommendation 26, and is included in the tables below.

Companies' witnesses addressed in their Rebuttal Testimonies. Some of the ORS recommendations were identified as recommendations the Companies should address in a modified IRP in this proceeding, and others were identified as long-term recommendations that could be addressed in a future IRP with guidance provided through the Companies' stakeholder engagement process.

Q. HOW DID THE COMPANIES RESPOND TO ORS'S REVIEW OF THEIR IRP REPORTS?

A. Mr. Snider correctly noted that ORS did "not give a final stamp of approval to the Companies' IRPs,"[5] and that ORS identified various areas in which it "recommends the Companies modify certain aspects of their IRPs to provide additional information to aid the Commission in its determination of whether to approve the Companies' IRPs pursuant to the requirements of Act 62."[6] Mr. Snider also commented that his testimony "Highlights how ORS and their technical consultants, Kennedy Associates, have undertaken a reasonable, technically objective and holistic review of the 2020 IRP's compliance with Act 62."[7] The Companies were able to satisfactorily address many of ORS's recommendations in the Duke Energy witnesses' Rebuttal Testimony in this proceeding, and the Companies noted that it would be able to address many others by working collaboratively with Stakeholders in future IRP proceedings. Mr. Snider stated in Rebuttal Testimony:

> In short, the Companies believe nearly all of the recommendations for additional information and improvement identified by ORS can be worked through efficiently as part of the Companies' ongoing resource planning

[5] Rebuttal Testimony of Glen Snider, p. 22, l. 7.
[6] Id. at p. 21, l. 25.
[7] Id. at p. 9, l. 13.

process without the administrative burden and costs associated with a modified IRP filing.[8]

STATUS OF ORS 2020 IRP RECOMMENDATIONS

Q. PLEASE PROVIDE AN UPDATE OF ALL OF THE ORS'S RECOMMENDATIONS THAT WERE IDENTIFIED IN ORS'S REPORTS.

A. The following tables contain the lists of ORS recommendations that I originally included in my Direct Testimony that are updated with the current status of each recommendation based on our review of testimony and the Companies' responses to discovery requests. The tables also identify the ORS witnesses who discuss issues in more detail in their respective testimonies. ORS witness Surrebuttal Testimonies focus on those recommendations that have not yet been completely resolved or that require additional discussion. Table 1 contains the immediate issues that the ORS Report recommended should be corrected in the 2020 IRP, and Table 2 contains the issues that should be addressed as soon as possible, preferably in the next annual update to the IRP, but no later than the next comprehensive IRP that the Companies plan to file in 2022.

Table 1
Recommendations for DEC and DEP in this IRP

Item	Recommendations for DEC and DEP in this IRP	Status	Addressed by ORS Witness
4	Recommended Companies provide detailed discussion in IRP Reports or appendices explaining how Astrapé 2018 Solar Capacity Value Study results were used to derive the assumed winter peak standalone solar capacity value of 1%. Recommended this information be included in a modified IRP in this proceeding.	Additional information provided in Kalemba Section V. Resolved.	Hayet

[8] Id. at p. 22, l. 16.

Item	Recommendations for DEC and DEP in this IRP	Status	Addressed by ORS Witness
5	Recommended Companies provide additional justification for selecting the Base Energy Efficiency ("EE")/Demand Side Management ("DSM") case as opposed to the High EE/DSM case for use in Portfolio A, given that the High EE/DSM case may provide greater customer benefits. Recommended this information should be included in a modified IRP in this proceeding.	Additional justification provided in Snider Exhibit 11. Resolved.	Hayet
6	Recommended that in addition to the sensitivity cases included in Table A-9, the Companies also evaluate high and low levels of EE/DSM using high fuel/CO_2 and low fuel/CO_2 assumptions. Recommended this information be included in a modified IRP in this proceeding.	Resolved for this IRP. However, this should be discussed further in the IRP Stakeholder process.	Hayet
9	Recommended the Companies provide tables summarizing the capital and operations and maintenance ("O&M") costs for compliance with environmental regulations by unit and by environmental regulation, and include descriptions explaining those costs. Recommended this information be included in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 10. Resolved.	Hayet
10	Recommended the Companies create a cross reference table that compares each resource modeled in PROSYM, including generating units, demand response, purchase contracts, sales contracts, EE, etc. to the corresponding data in the Load, Capacity and Reserves ("LCR") table, on a resource by resource basis. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 6. Resolved.	Hayet
11	Recommended the Companies supply additional information regarding its Nuclear Unit relicensing plans (including a timeline) and its plans to conduct economic evaluations to assess the benefits of relicensing the units. Also, recommended the Companies provide additional insight into why it is beginning this process so far in advance of the relicensing dates. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 7. Resolved.	Hayet

Item	Recommendations for DEC and DEP in this IRP	Status	Addressed by ORS Witness
12	DEC Only - Recommended that DEC provide the status of its plans to relicense the Bad Creek Pumped Hydro units, including any actions it will have to take as part of the relicensing process and any costs that it will incur to relicense the units. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 8. Resolved.	Hayet
13	Recommended DEP and DEC provide additional clarification regarding their plans for the retirement of the Darlington and Allen units, respectively, including details about any transmission impacts, an explanation of the steps being pursued to receive final approval from any regulatory body, and a timeline for conducting these activities. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 15 (Darlington Units), and Snider Exhibit 17 (Allen Units). Resolved.	Hayet
14	Recommended the Companies provide evidence that the optimal retirement dates determined with the Sequential Peaker Method ("SPM") are comparable to the optimal retirement dates the System Optimizer model would produce if it were used in the retirement study. Recommended this information be provided in a modified IRP in this proceeding.	See Snider Rebuttal Testimony, beginning at page 84. The Companies are willing to collaborate with stakeholders and evaluate Encompass' capabilities to potentially improve the modeling process. Resolved.	Hayet
15	Recommended the Companies supply additional information explaining the basis for how Combined Heat and Power ("CHP") resources were added to the short-term action plan, and explain why CHP resources were not treated as selectable resources in the economic optimization process, if in fact they were not. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 16. The treatment of CHP resources in future IRPs should be considered in the stakeholder process. Resolved.	Hayet

Item	Recommendations for DEC and DEP in this IRP	Status	Addressed by ORS Witness
16	Recommended the Companies provide additional justification for its Combustion Turbine ("CT") capital cost assumption. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 9. Resolved, but discuss the reasonableness of basing the CT cost on building 4 CT units at a site in a future stakeholder process	Hayet
17	Recommended the Companies provide additional justification for its Battery Energy Storage fixed O&M cost and capacity factor assumptions. Recommended this information be provided in a modified IRP in this proceeding.	Addressed in both Mr. Snider's and Mr. Kalemba's testimony. Resolved, but battery storage capacity factor should be re-examined when the Companies begin using Encompass.	Hayet
18	Recommended the Companies include an additional solar generic resource option in its IRP modeling assumptions that reflects the kind of solar Purchase Power Agreements ("PPA") prices that may be available in the market. As a proxy, the Companies could assume $38/megawatt-hour ("MWh") as the solar PPA cost. Recommended this be addressed in a modified IRP in this proceeding.	Unresolved. The Companies should be required to adopt market-based solar PPAs in the 2021 update IRP.	Hayet
20	Recommended the Companies provide a table identifying each renewable resource option that was modeled, and include whether the resource was forced-in or economically selected (System Optimizer or other approach), the reason the resource was forced-in (e.g. Competitive Procurement of Renewable Energy Program ("CPRE"), Act 236, etc.), whether the resource is a designated, mandated, or undesignated resource, and where the resource is found in the PROSYM database and in the LCR tables for reconciliation purposes. Recommended this information be provided in a modified IRP in this proceeding.	Additional information provided in Kalemba Exhibit 1. In future IRPs, should the Companies follow the same categorization process, additional information should be included regarding whether resources were forced-in or economically selected. Resolved.	Hayet

Item	Recommendations for DEC and DEP in this IRP	Status	Addressed by ORS Witness
21	Recommended the Companies include post in-service capital costs for new resource additions in its capital cost model and its Present Value of Revenue Requirement ("PVRR") calculations for each Portfolio and each sensitivity of each Portfolio. Recommended this be addressed in a modified IRP in this proceeding.	See Snider Rebuttal Exhibit 12. The Companies should separate out these costs in future IRP filings and identify them as post in-service capital additions. Resolved.	Kollen
22	The average retail rate impacts are an important consideration when assessing whether Portfolios and the pathways reflected in those Portfolios are reasonable. This should be considered in this IRP and future IRPs, but it does not require a modified IRP in this proceeding.	This recommendation only pointed out that this is important information to be considered in evaluating a utility's IRP. Resolved.	-
23	Recommended the Companies revise the calculation of the average retail rate impact on customers so that the assumptions and methodologies are consistent with the calculations of the PVRR, except for the levelization of the capital-related costs. Recommended this be included in a modified IRP in this proceeding.	Unresolved. Companies are amenable to addressing this in the Stakeholder process. ORS recommends this be done before the next IRP Update in 2021.	Kollen
24	Recommended the Companies provide additional details and status updates about resources included in the action plan, including coal retirements, the Lincoln CT project, unnamed energy storage projects, nuclear uprates, Bad Creek upgrades, and unnamed CHP projects. Recommended this information be included in a modified IRP in this proceeding.	Additional information provided in Snider Exhibit 14. Company also committed to provide this information in future IRPs. Resolved.	Hayet

Q. PLEASE PROVIDE THE LIST OF RECOMMENDATIONS THAT SHOULD BE ADDRESSED AS SOON AS POSSIBLE, BUT NO LATER THAN THE NEXT COMPREHENSIVE IRP IN 2023.

A. The recommendations are included in the following table.

Table 2
Recommendations for DEC and DEP in a Future IRP

Item	Recommendations for DEC and DEP in a Future IRP	Status	Addressed by ORS Witness
1	Recommended the Companies provide more detailed discussions describing each of the load forecasting models, statistical results, and the individual energy and peak load forecast results. Recommended this level of detail be included in a technical appendix to the IRP.	Companies offer to provide this information in response to discovery, not as a technical appendix. (Snider Rebuttal Testimony, beginning at pg. 50, ln. 15). Resolved.	Baron
2	Recommended the Companies provide a more detailed discussion of the specific reliability methodology used to develop the synthetic loads for extreme low temperature periods in a technical appendix to the IRP.	Companies agreed to provide this information in future IRP proceedings. (Snider Rebuttal Testimony, pg. 53, ln. 12 - 17). Resolved.	Baron
3	Recommended further development of the reliability methodology to model the effects of extreme low temperatures on winter peak load. Recommended this be addressed in future IRPs through the Companies' stakeholder process.	Witness Snider stated that this issue is critical to resource adequacy planning and further development would take place. (Snider Rebuttal Testimony, beginning at pg. 54, ln. 1). Resolved.	Baron
7	The Companies provided no basis for the low EE/DSM forecast. Recommended additional justification be provided or consider other approaches for deriving the low EE/DSM forecast. Recommended this be addressed in future IRPs through the stakeholder process.	Witness Bak agreed to address this "with stakeholders for their next IRPs." (Bak Rebuttal Testimony, beginning at pg. 19, ln. 3). Resolved.	-
8	Recommended the Companies review their natural gas price forecasting methodology and investigate alternative approaches. Recommended this be addressed in future IRPs through the stakeholder process.	Witness Snider stated this would be addressed in a future IRP Stakeholder process. (Snider Rebuttal Testimony, beginning at pg. 64, l. 19). Resolved.	-

Item	Recommendations for DEC and DEP in a Future IRP	Status	Addressed by ORS Witness
19	Given the importance that solar capacity values and solar plus battery energy storage capacity values potentially could have on the IRP analysis, ORS recommended that further investigation be conducted regarding these values with stakeholder input, discussed as part of a stakeholder engagement process.	Witness Kalemba states the Companies are open to discussing this issue with Stakeholders, and would consider performing additional sensitivities in future IRPs. (Kalemba Rebuttal Testimony, beginning at pg. 43, l. 8). Resolved.	-
25	Recommended in future IRPs, additional details be provided regarding the status of the Southeast Energy Exchange Market ("SEEM").	Witness Snider stated this would be provided in future IRPs. (Snider Rebuttal Testimony, pg. 151, ln. 20 – 22.). Resolved.	-
26[9]	Recommended that the Companies perform risk analyses in future IRPs.	The Companies agreed. (Snider Direct Testimony at pg. 143, ln. 16). Resolved.	Kollen

<u>Remaining Issues Regarding Recommendations for this IRP</u>

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATION #4 CONCERNING THE DERIVATION OF THE 1% WINTER CAPACITY VALUE FOR STANDALONE SOLAR RESOURCES.

A. Through Recommendation #4, ORS requested the Companies provide a detailed discussion of how the results of the Astrapé 2018 Solar Capacity Value Study were used to derive the Companies' 1% winter peak standalone solar capacity value assumption. Companies witness Kalemba provided the requested discussion in Section V of his Rebuttal Testimony. Mr. Kalemba explained that both the 2016 and 2020 Resource

[9] This recommendation was addressed by ORS witness Kollen at p. 11 of his Direct Testimony, but it was not previously assigned a recommendation number. It is now Recommendation 26.

Adequacy Studies performed by Astrapé determined that most of the Loss of Load Expectation ("LOLE") hours occurred in the winter. Because both the Companies' 2016 and 2020 Resource Adequacy Studies found that most of the LOLE hours occurred in the winter period, the Companies decided it would not be necessary to update the Effective Load Carrying Capability ("ELCC") results from the 2018 Solar Capacity Value Study in the 2020 IRP, and it could apply those ELCC results to the Fixed Tilt Solar and the Single Axis Tracking Solar resources to derive the Companies' capacity value assumption. Mr. Kalemba described at length the Companies' expectations about a shift over time to more Single Axis Tracking Solar relative to Fixed Tilt Solar, but ultimately for study purposes in this IRP, the Companies assumed that over the long term the growth in solar would maintain a 50/50 blend of the two types of solar resources.[10] Ultimately, the Companies presented the results of its capacity value assessment at different increments of solar resource additions in Figure 17 in Mr. Kalemba's Rebuttal Testimony, and the Companies concluded from those results that 1% was a reasonable value to use for solar capacity value.

Q. IS ORS SATISFIED WITH THE COMPANIES' EXPLANATION OF HOW THE RESULTS OF THE ASTRAPÉ SOLAR CAPACITY VALUE STUDY WERE USED TO DERIVE THE COMPANIES' 1% WINTER PEAK STANDALONE SOLAR CAPACITY VALUE ASSUMPTION?

A. Yes. ORS is satisfied that the Companies have provided the information that ORS requested, which was an explanation of the basis the Companies relied on in deciding to use 1% as its solar capacity value assumption. However, the solar capacity value assumption is an important modeling assumption that requires continuing investigation to

[10] Rebuttal Testimony of Matthew Kalemba, p. 30, l. 8 through p. 34, l. 7.

ensure that the Companies have accurately derived the capacity value of solar. It appears that the Companies are willing to investigate the capacity value of solar assumption further as Mr. Snider stated that the "Companies agree to review these values as part of the IRP stakeholder process."[11] ORS is satisfied the Companies have addressed Recommendation #4 for purposes of this IRP.

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATION #5.

A. ORS Recommendation #5 concerns the Companies' decision to select its Base EE/DSM assumptions as opposed to its High EE/DSM assumptions for use in its Base Case portfolios. One of the reasons given in the Companies' IRP Reports for not selecting the High EE/DSM assumptions relates to a concern about "executability risk."[12] ORS requested that the Companies provide additional justification for the selection given the potential that the High EE/DSM could provide greater customer benefits.

Q. WHAT WAS THE COMPANIES' RESPONSE?

A. Companies' witness Snider explained that a higher case represents:[13]

> …..additional savings potential that are more aspirational in nature and more dependent upon future demonstration of potential savings that may be possible through yet to be Commission approved future EE/DSM offerings. While it is certainly the Companies' hope that it will be able to achieve these higher savings as it works with stakeholders to develop additional cost-effective programs, to present for Commission approval, it is premature to count on these additional savings for the base case analysis as it has the effect of increasing reliability risk through dependence on EE savings that have less certainty of achievement than the base case savings. It is important to note that as we move through time, if future potential savings become more certain through Commission approved programs, those savings will move into the base case in future IRPs.

[11] Rebuttal Testimony of Glen Snider, p. 124, l. 15.
[12] DEC 2020 IRP, p. 171, and DEP 2020 IRP, p. 170.
[13] Rebuttal Testimony of Glen Snider, p. 137, l. 11.

Q. WHAT OTHER JUSTIFICATION DID THE COMPANIES PROVIDE?

A. Additionally, Mr. Snider spotlighted the fact that, when the Companies performed sensitivity analyses and considered a high EE sensitivity case, the high EE sensitivity case resulted in a relatively small reduction (less than 2% for DEP and less than .5% for DEC) in total present value revenue requirements ("PVRR") over the study horizon (DEC and DEP 2020 IRPs, Table A-9). However, other sensitivities (also in Table A-9) reflected far greater impacts on PVRR results.

Q. ARE THERE ANY OTHER REASONS WHY THE COMPANIES' BASE EE FORECAST MAY BE CONSIDERED REASONABLE?

A. Yes, the ORS Reports pointed out that the amount of energy savings that the Companies have achieved ranks the Companies in the top quartile compared to other states based on a ranking conducted by the American Council for an Energy Efficient Economy ("ACEEE") in its 2019 State Energy Efficiency Scorecard.[14] Also, Companies' witness Bak noted that the Southern Alliance for Clean Energy ("SACE") stated that Duke Energy was found to lead the southeast in energy efficiency every year from 2017 to 2019.[15]

Q. DID THE COMPANIES ADEQUATELY ADDRESS ORS RECOMMENDATION #5?

A. Yes. For purposes of this IRP, the Companies adequately justified its selection of the Base EE/DSM assumptions for its Base Case. The Companies indicated repeatedly that they are willing to work with interested parties in its EE/DSM Collaborative. The Companies should continue to work closely with stakeholders in that forum, and if the

[14] Exhibit AMS-1, ORS DEC Report at p. 48.
[15] Rebuttal Testimony of Brian Bak, p. 7, beginning at l. 12.

opportunity to achieve greater energy savings can be identified, the Companies should investigate those opportunities in that forum and include those results in the next comprehensive IRP in 2022.

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATION #6.

A. ORS recommended that, in addition to the high and low EE/DSM sensitivity cases conducted using Base Case fuel and CO2 assumptions, the Companies should evaluate high and low EE/DSM cases under different fuel and CO2 assumptions. Duke Energy witness Snider indicated that compliance with ORS's request would create "an extraordinary amount of additional work that may be of limited value considering the analysis already performed on this variable."[16] The sensitivity cases that the Companies did perform did not demonstrate that the results were overly sensitive to changes in EE/DSM assumptions.

While additional sensitivity analysis may result in a relatively minor change, this issue should not be completely ignored. Other utilities including Dominion Energy South Carolina, Inc. ("DESC") do conduct EE/DSM sensitivities across a range of fuel and CO_2 assumptions, particularly to understand what level of EE/DSM should be implemented if fuel costs rise or if higher CO_2 costs are imposed. The Companies use of the System Optimizer resource optimization model to run sensitivity analysis does increase the workload and ORS understands that the Companies plan to use its new optimization model, Encompass, in future IRPs.[17] Given that the Companies will be transitioning to a new

[16] Rebuttal Testimony of Glen Snider, p. 139, l. 12.
[17] *Id*. at p. 82, l. 5.

optimization model, and given that the Companies have already demonstrated that greater levels of EE/DSM may not be overly impactful, ORS no longer makes Recommendation #6 for this IRP, but recommends instead that this issue be brought up for further discussion as part of the Companies' IRP stakeholder process. As part of that process, parties could evaluate whether there may be a subset of runs that could be performed and could consider whether the Encompass model has a means by which the Companies could simplify the portfolio optimization process.

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATION #9.

A. ORS recommended that in their IRPs, the Companies should provide tables containing environmental capital and operating and maintenance costs, and the information should be provided by generating unit and by environmental regulation. Companies' witness Snider responded by providing the requested information in Confidential Exhibit 10 attached to his Rebuttal Testimony. ORS appreciates that the Companies supplied the information in the format requested, which has been helpful in reviewing all of the environmental costs that the Companies anticipate would be incurred if the Companies continue to operate their coal units. Given concerns about confidentiality, Mr. Snider expressed a preference for providing this information in future IRPs via responses to discovery requests. The Companies have provided the information requested by ORS in this IRP, and ORS will request this information in future IRPs via discovery requests, if necessary.

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATION #10.

A. ORS encountered some difficulty reconciling PROSYM data with other information the Companies provided, including the Companies' LCR Tables, and therefore requested the Companies to supply a cross-reference table to help reconcile the differences. Mr. Snider provided the requested information as Exhibit 6 to his Rebuttal Testimony, which contained a cross reference table and included approximately 25 notes explaining the differences between the PROSYM data and the LCR Table. In his Rebuttal Testimony, Mr. Snider explained that, in the future, the Companies will transition to the Encompass modeling software, which will be used for both production cost modeling and optimization analysis. In future IRPs, the Companies' presentation of loads, resources, and reserve margin may align more closely with the data used for production cost modeling and optimization analysis. The Companies have provided ORS the requested reconciliation in this IRP.

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATIONS #11 AND #12, REGARDING NUCLEAR AND BAD CREEK PUMPED STORAGE UNIT RELICENSING PLANS.

A. With regard to the Companies' nuclear units, ORS noted that the Companies have already made the decision to relicense its fleet of 11 nuclear units when the unit's licenses expire between 2030 and 2046. ORS's Recommendation #11 sought additional information concerning the relicensing status, including an explanation of why the Companies have begun the process with the Oconee units, whose licenses will not expire until 2033, given there is another unit in the fleet, Robinson 2 whose license will expire in 2030. Mr. Snider provided additional information in Exhibit 7 to his Rebuttal Testimony, which explained that the Companies will have to file a Subsequent License Renewal

("SLR") application by 2025 for the Robinson nuclear plant, and by 2029 for the Brunswick nuclear plant, as five years is required to conduct the relicensing process with the Nuclear Regulatory Commission ("NRC"). The Companies chose the Oconee plant to relicense first because it is the largest nuclear plant in the Companies' fleet. The Companies sufficiently addressed the ORS request for additional information. Also, in Exhibit 7 of Mr. Snider's Rebuttal Testimony, the Companies state that prior to filing the 2019 IRP, the Companies performed an economic evaluation and found that relicensing the nuclear fleet would be economic. The economic evaluation and analysis should be updated by the Companies prior to committing funds to relicensing the nuclear units and should be presented to the Commission in a future IRP. This appears to be consistent with the Companies' intentions as Appendix N to the 2020 IRP Reports states, "Duke plans to diligently review the business case for relicensing existing nuclear units, and if relicensing is in the best interest of customers, pursue second license renewal."

With regard to DEC's Bad Creek Pumped Storage Plant, ORS identified that DEC intends to relicense the plant in 2027 and ORS requested in Recommendation #12 that DEC provide additional details regarding the status of its relicensing efforts. Mr. Snider provided additional information in Exhibit 8 to his Rebuttal Testimony. Mr. Snider explained that DEC intends to file a Notice of Intent and Pre-Application Document in 2022 and will utilize the Federal Energy Regulatory Commission's ("FERC") Integrated Licensing Process, which will allow multiple parties the opportunity to participate in the relicensing process. DEC indicated that it has not yet developed cost estimates for the relicensing process, but committed to including a status update on the Bad Creek relicensing in future IRPs. The Companies have provided the information recommended by ORS in this IRP.

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATION #13.

A. With regard to the DEP Report, ORS's Recommendation #13 sought clarification of the status of the Darlington units. DEP's IRP Report in the Short Term Action Plan (Section 14) indicates that Darlington CT 1-4, 6-8, and 10 (514 MW) will retire in 2021; however, it appears the units have already been retired by DEP. Mr. Snider provided additional clarification in Exhibit 15 of his Rebuttal Testimony that confirmed the units were retired shortly prior to the filing of the 2020 IRP. The units were listed in the Short Term Action Plan in 2021 to denote they would be retired prior to 2021. DEP also supplied additional details in Exhibit 15 about the transmission support service role the Darlington units provided to the Robinson Nuclear Station, which was addressed by installing automatic load tap changing transformers at the Robinson Station prior to the retirement of the Darlington units. Currently, Darlington Units 12 and 13 are still operational units at the site.

With regard to the DEC Report, ORS's Recommendation #13 sought clarification of the status of the Allen coal-fired units. DEC indicated in its IRP Report that it intends to retire Allen Units 2 through 4 prior to the end of 2021. Mr. Snider provided additional information in Exhibit 7 to his Rebuttal Testimony, which included a more current update and states that Allen 3 unit would be closed as of March 31, 2021, while the Allen 2 and 4 units would still be retired later in 2021. The Companies also informed the Commission of their intention to close Allen 3 in a letter they sent on February 2, 2021, stating the unit would no longer provide economic and reliable commercial service to customers. Furthermore, the Companies indicated that no transmission impacts would result from the retirement of the Allen 2 – 4 units. However, prior to the retirement of the Allen 1 and 5 units by year end 2023, DEC would have to construct a new switching station with larger transformer banks and new breakers/switches that would be needed due to the Allen unit retirements. Based on this information, the Companies have provided the information recommended by ORS in this IRP.

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATION #14.

A. The Companies evaluated coal retirements using an approach known as the SPM. The SPM approach relies partly on an optimization analysis and partly on production cost modeling. ORS expressed a concern that a better approach might be to rely entirely on an optimization method and recommended the Companies perform an analysis demonstrating they did not produce suboptimal results using the SPM approach. Beginning at the bottom of page 84 of his Rebuttal Testimony, Mr. Snider provided a detailed explanation of the SPM approach, and he expressed a willingness for the Companies to collaborate with stakeholders to potentially enhance the Companies' modeling process, particularly given that the Companies would be switching to the new Encompass optimization model. Mr. Snider stated,[18]

> However, given the complexity and rigorous analysis required to analyze coal retirements, the Company proposes to engage with ORS and their technical consultants to discuss potential enhancement techniques for evaluating coal retirements for future comprehensive IRPs. Since the Company is switching to the Encompass model as discussed in the stakeholder process, we will also continue to evaluate the capabilities and

[18] Rebuttal Testimony of Glen Snider, p. 85, l. 8.

enhancements our new modeling software will provide with respect to co-optimizing retirements of the Companies' coal fleet.

Furthermore, the Companies expressed a commitment to evaluate whether the Encompass software would be capable of fully optimizing retirement dates and replacement options in the next Comprehensive IRP filing in 2022.[19] The Companies' proposed resolution for ORS Recommendation #14 is reasonable and no further action is necessary in this IRP.

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATION #15.

A. ORS's Recommendation #15 relates to the two unnamed CHP units (total capacity of 60 MW) that DEC forced into its resource plan. Recommendation #15 sought additional clarification why those units were forced-in and appear in the Companies' Short-Term Action Plan. Mr. Snider provided additional information in his Exhibit 16, in which he stated that the CHP projects are "near-term initiatives and programmatic approaches to providing customers with steam and, potentially, electricity," and the Companies included the units to alert parties of their intention to continue pursuing CHP solutions for a variety of customer needs (onsite generation and steam production for industrial process, heating, cooling or other needs). It is not clear to ORS why the units were only included in DEC's resource plan and not DEP's. The Companies further asserted in Exhibit 16 that they would only build such units after working extensively with the interested customer.

CHP resources should be developed if the economic evaluation demonstrates the CHP units are beneficial to customers. However, as the Companies note in Exhibit 16, the

[19] Id. at p. 85, l. 15.

selection of CHP resources is customer-specific, and for that reason ORS recommends that additional consideration of the treatment of CHP units in future IRPs should occur within the Companies' stakeholder process.

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATION #16.

A. ORS noticed that the Companies' CT capital cost assumption appeared to be low compared to other sources of data ORS identified, including data obtained from the Energy Information Administration ("EIA"), the National Renewable Energy Lab ("NREL"), Lazard, the Nuclear Regulatory Commission ("NRC"), DESC, and Kentucky Power and Southwestern Electric Power Company ("SWEPCO"), which are both AEP companies. Mr. Snider provides a detailed assessment of ORS's CT capital cost comparison in Exhibit 9 to his testimony. Mr. Snider's explanation for why the Companies' capital cost assumption is lower than the data the ORS identified is that the Companies assume that four units would be built at a site, while some of the other estimates assume that just one unit would be built at a site. Mr. Snider explains that a four unit capital cost estimate would be much lower on average compared to a single unit capital cost estimate due to economies of scale, and some of the other sources (EIA, NREL, Lazard, NRC) referenced above, based their cost estimates on the assumption that only one unit would be built at a site. Mr. Snider explains that had the Companies' capital cost estimate been based on building just a single unit, the Companies' estimate would have been much higher,[redacted] instead of the Companies' average four (4) unit estimate, $[redacted]/kW [end confidential]. Mr. Snider explains that a more reasonable evaluation would be to compare the Companies' cost of building the first of four CT units, [redacted]to EIA's cost of a single CT, which is

$661/kW. Had that comparison been made, the Companies cost would have been much closer to the other sources, such as EIA. ORS finds the Companies' explanation for its CT capital cost assumption to be reasonable, however, ORS recommends that in a future stakeholder process, the Companies should discuss the reasonableness of building four CT units at a time.

Q. DID THE COMPANIES ADEQUATELY ADDRESS ORS'S RECOMMENDATION #17?

A. Yes. ORS assessed that the Companies' Fixed O&M assumption for generic battery storage resources appears to be considerably higher than other estimates ORS identified. In Rebuttal Testimony, Duke Energy witness Kalemba appears to agree with ORS's assessment, however, he indicated he believes the overstatement amounts to a "non-material issue."[20] The Companies identified an error which contributed to the inflated Fixed O&M costs, and Mr. Kalemba states that the Companies will correct the error in the upcoming 2021 IRP Update.[21] The Companies argue the discrepancy identified by ORS does not materially impact the final analysis. Mr. Kalemba provides a chart (Kalemba Rebuttal Figure 11) that shows the high starting Fixed O&M cost in 2020, and then shows how it declines very quickly to the point that it drops below NREL's Fixed O&M cost estimate by 2025. It does not appear that the high initial Fixed O&M cost would materially change the results of the IRP, and the Companies have committed to correct the discrepancy in the 2021 IRP Update.

[20] Rebuttal Testimony of Matthew Kalemba, p. 27, l. 19.
[21] *Id*. at p. 28, l. 1.

Regarding ORS's concern that the Companies' battery energy storage capacity factor is not aligned with other sources, Mr. Snider discusses the capacity factor at page 116 of his Rebuttal Testimony and explains the battery energy storage capacity factor is derived from the dispatch of the battery resources in the Companies' production cost model. Furthermore, Mr. Snider suggests that because the Companies already have a pumped storage energy storage resource, the utilization of additional energy storage resource may be limited. The Companies' explanation is reasonable, and ORS recommends the battery energy storage capacity factor be monitored and re-evaluated when the Companies begin using the Encompass model. ORS is satisfied that this issue is addressed for purposes of this IRP.

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATION #18.

A. ORS noted that the Companies' levelized cost of solar energy was higher than estimates from other sources that ORS identified. As a result, ORS recommended the Companies include options reflecting the kind of solar PPA prices that may be available in the market. ORS also suggested, as a proxy, the Companies could include $38/MWh as the solar PPA cost, which was consistent with Duke's own recent 20-year PPA purchases in the 2019 North Carolina Competitive Procurement of Renewable Energy ("CPRE") Tranche 1 acquisitions.[22]

In Rebuttal Testimony, Companies witness Snider explained that comparing the 30-year life of a company-built asset against a 20-year PPA creates an "apples-to-oranges

[22] PSCSC December 23, 2020, Order No. 2020-832, DESC 2020 IRP, Docket No. 2019-226-E, p. 47, https://dms.psc.sc.gov/Attachments/Order/a4b59f43-e545-43bd-9f35-a846b7602c39

comparison,"[23] and creates risk at the tail 10-year period after the PPA expires. Mr. Snider's argument misconstrues ORS's Recommendation #18. ORS's recommendation is to fairly consider the options available in the market, and ORS never stated that PPA acquisitions had to be limited to 20-year terms. A simple means to assuage Mr. Snider's concern would be to model the assumed cost of a 30-year PPA in addition to the cost of the self-built solar resource option.

In comments the Companies filed in an avoided cost proceeding in South Carolina,[24] the Companies provided a source for 30-year solar PPA prices, and noted that prices close to $38/MWH have been available to it and its regional neighbors. Specifically, in those comments, the Companies noted that in 2017 Georgia Power acquired 30-year solar PPAs at an average price of $36/MWh,[25] and in 2019, acquired 30-year PPAs at an average price of $34/MWh.[26] (*See* Surrebuttal Exhibit PH-1). Duke used this information in the avoided cost proceeding to argue that long-term PPAs for solar resources below $40/MWh could be available in the market.[27] The LCOE of solar resources based on Duke's assumed cost for a self-build solar resource in this IRP is $[redacted]/MWh, which is much higher than the below $40/MWh price that Duke noted was available in the market for a 30-year PPA.

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[23] Rebuttal Testimony of Glen Snider, p. 120, l. 9.
[24] Docket No. 2019-185-E and 186-E, November 8, 2019, South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's and Duke Energy Progress LLC's Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A), "Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's Response to Power Advisory Report", https://dms.psc.sc.gov/Attachments/Matter/72a57f5e-ac62-41e3-a47d-a0a6b41a3db7
[25] *Id*. at p.21.
[26] *Id*. at p. 22.
[27] *Id*. at p. 22.

Given solar PPAs' lower pricing, solar PPAs should be considered and modeled as a resource option in the IRP. The Companies' IRP restricts its optimization model to only consider a self-build solar resource that is inconsistent with market pricing. The Companies are aware of Solar PPAs for a variety of term lengths that are available in the mid-$30/MWh range, and failure to model at least one additional option is not in the best interest of customers. Given the upcoming 2021 IRP update is so near, ORS recommends the Companies include market-based solar PPAs in the upcoming IRP.

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATION #20.

A. While reviewing the Companies' IRP Reports and discovery, ORS had difficulty reconciling the different information sources and the categorization system the Companies used for solar resource additions. As a result, ORS recommended the Companies provide a table that lists each renewable resource in the expansion plan, whether it was economically selected or forced-in, the reason a resource was forced-in, whether that resource was categorized as designated, mandated, or undesignated, and where each resource appeared in the LCR tables and PROSYM databases.

Companies witness Kalemba provided a table in Exhibit 1 to his Rebuttal Testimony containing most of the information ORS recommended. The table contains all of the requested information except whether each resource was economically selected or forced-in, and the reason why the resource was forced-in. Because the forced-in versus economic categorization system is not mutually exclusive to the designated/mandated/undesignated categorization system, ORS is unable to identify which resources are forced-in and which are economically selected. It is possible that designated and undesignated resources could be economically selected or forced-in. Knowing which resources were forced-in, and why, would aid in ORS's understanding of whether the Companies force-in solar resources beyond what is mandated, or to what extent mandated resources may have been economically selected if the mandates had not existed. ORS recommends the Companies continue to provide a table like Witness Kalemba's Rebuttal Testimony Exhibit 1, but include a column to identify which resources are forced-in and which are economically selected, as well as the reason the resource was forced-in.

Q. PLEASE DISCUSS THE COMPANIES' RESPONSE TO ORS'S RECOMMENDATION #24.

A. ORS recommended the Companies provide additional details regarding items included in the Companies' Short-Term Action Plan, including coal retirements, the Lincoln CT project, unnamed energy storage projects, nuclear uprates, Bad Creek upgrades, and unnamed CHP projects. Companies witness Snider provided additional details regarding these resources in Exhibit 14 of his Rebuttal Testimony. The Companies provided the information recommended by ORS in this IRP and have committed to provide the same information in future Short-Term Action Plans.[28]

Q. WILL YOU UPDATE YOUR SURREBUTTAL TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental testimony should new information not previously provided by the Companies, or other sources, becomes available.

[28] Rebuttal Testimony of Glen Snider, p. 149, l. 11.

Q. DOES THIS CONCLUDE YOUR SURREBUTTAL TESTIMONY?

A. Yes.

BEFORE

THE PUBLIC SERVICE COMMISSION OF

SOUTH CAROLINA

DOCKET NO. 2019-185-E
DOCKET NO. 2019-186-E

In the Matter of: South Carolina Energy Freedom Act (H.3659) Proceeding to Establish Duke Energy Carolinas, LLC's and Duke Energy Progress LLC's Standard Offer Avoided Cost Methodologies, Form Contract Power Purchase Agreements, Commitment to Sell Forms, and Any Other Terms or Conditions Necessary (Includes Small Power Producers as Defined in 16 United States Code 796, as Amended) – S.C. Code Ann. Section 58-41-20(A)	)	**DUKE ENERGY CAROLINAS, LLC'S AND DUKE ENERGY PROGRESS, LLC'S RESPONSE TO POWER ADVISORY REPORT**

Pursuant to Order No. 2019-107-H issued on September 24, 2019, Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and, together with DEC, the "Companies" or "Duke"), by and through counsel, hereby respond to the Independent Third-Party Consultant Final Report Pursuant to South Carolina Act 62, as filed with the Commission by Power Advisory LLC ("Power Advisory") on November 1, 2019, in the above-captioned proceedings ("Power Advisory Report" or the "Report"). In response to the Power Advisory Report, the Companies state the following:

I. General Comments

Power Advisory's statutory role in this proceeding is to provide the Commission with an independent, third-party assessment of Duke's avoided cost rates, methodologies, terms, calculations, and conditions and "to inform the Commission's decision setting the avoided costs for each electrical utility." *See* S.C. Code. Ann. § 58-41-20(I).

Based upon the Companies' review of the Report, most of Power Advisory's conclusions regarding Duke's calculation of avoided costs are reasonable and are appropriately based upon the extensive information provided by Duke through the Companies' Application, testimony, and discovery as well as the testimony offered by the Office of Regulatory Staff ("ORS") and other parties. However, the Companies do believe that certain of Power Advisory's findings and recommendations to the Commission either do not fully consider all evidence in the record or, in some cases, are inappropriately based upon considerations outside the evidentiary record. Therefore, while the Companies are generally supportive of many of Power Advisory's findings and recommendations, Duke believes it important to highlight areas of the Report where Power Advisory's conclusions are either incorrect or where the conclusions are not based on the evidentiary record of this proceeding, and as a result, cannot be reasonably relied upon by the Commission. Section II of Duke's comments addresses these evidentiary issues. Section III then provides the Companies' comments on the technical discussion and conclusions in the Report.

II. Concerns with Conclusions in the Power Advisory Report Based Upon New Information Not in Evidence

The Companies are cognizant that this is the first time the Commission has engaged a third-party consultant under the new Act 62 framework to review a utility's calculation of avoided costs and to help inform the Commission's consideration of the contracting documents used to govern sales of power by QFs to the utility. The Companies anticipate the role of the third-party consultant may evolve in future cases. However, the timing and content of certain sections of the Report are procedurally objectionable.

A. The Power Advisory Report Draws Conclusions Based on New Information Not in Evidence, in Contradiction to the Commission's Ex Parte Prohibitions and Act 62

Act 62 directs the Commission to engage "a qualified independent third party to submit a report that includes the third party's independently derived conclusions as to that third party's opinion of each utility's calculation of avoided costs." S.C. Code Ann. § 58-41-20(I). The statute specifically grants the third-party consultant the right to submit requests for documents and information under the authority of the Commission and directs that "[t]he qualified independent third party's duty will be to the commission." 58-41-20(I). With respect to the report, Act 62 directs that "[a]ny conclusions [of the consultant] ***<u>based on the evidence in the record and included in the report are intended to be used by the commission</u>*** along with all other evidence submitted during the proceeding to inform its ultimate decision setting the avoided costs for each electrical utility." S.C. Code Ann. § 58-41-20(I) (emphasis added).

Importantly, Act 62 also subjects the third-party consultant to the ex parte prohibitions contained in Chapter 3, Title 58. S.C. Code Ann. § 58-3-260 governs the conduct of communications between the Commission and parties:

> (B) Except as otherwise provided herein or unless required for the disposition of ex parte matters specifically authorized by law, a commissioner, hearing officer, or commission employee shall not communicate, directly or indirectly, regarding any issue that is an issue in any proceeding or can reasonably be expected to become an issue in any proceeding with any person without notice and opportunity for all parties to participate in the communication, nor shall any person communicate, directly or indirectly, regarding any issue that is an issue in any proceeding or can reasonably be expected to become an issue in any proceeding with any commissioner, hearing officer, or commission employee without notice and opportunity for all parties to participate in the communication.

Subsection 58-3-260(C) exempts several categories of communication from the prohibitions of subsection B and specifically provides that commissioners, hearing officers, and commission employees may "receive aid from commission employees if the commission employees providing aid *do not . . . furnish, augment, diminish, or modify the evidence in the record*." S.C. Code Ann. § 58-3-260(C)(8)(b) (emphasis added).

Four sections of the Power Advisory Report (4.1.1, 4.1.3, 4.4.1, and 4.4.2) introduce facts and information that have not been admitted into the evidentiary record of these proceedings. Because these facts are not included in the evidentiary record, the Companies have not had an opportunity to properly review and analyze them in the same manner that is afforded to parties with regard to facts that are included in the evidentiary record. As such, the introduction of this new information in the Power Advisory Report is inappropriate, and it would be improper for the Commission to draw conclusions from the new information presented in the Report.

For example, Section 4.4.1 of the Power Advisory Report introduces new facts about a Georgia Power competitive solicitation where Power Advisory states that "[i]n late 2017, through competitive bid, Georgia Power contracted for 510 MW of solar in Georgia with an average price of $36/MWh for 30-year contracts."[1] Power Advisory cites to a Georgia Power Company press release, which was not introduced at hearing into the evidentiary record of this proceeding.[2] Importantly, this press release does not actually identify the 30-year PPA term or average solar capacity price identified by Power Advisory as procured under this program.[3] Thus, in addition to improperly introducing new

[1] Power Advisory Report, at 34.
[2] Power Advisory Report, at 34, fn. 109.
[3] Power Advisory Report, at 35.

information, the Report fails to provide source information establishing the validity of these facts and figures to the Commission.

In Section 4.1.3, Power Advisory introduces Figure 5, "PURPA Contract Length by State Sorted Longest to Shortest," which Power Advisory has created to provide information on the standard offer contract term lengths from 15 States.[4] As its supporting reference for Figure 5, Power Advisory's citation states that the information was based upon "various regulatory filings, Standard Offer PPAs and associated documents."[5] First, this vague citation is problematic because it prevents the Commission or the parties from reviewing any information underlying Power Advisory's development of Figure 5. Additionally, Figure 5 (and the underlying "various regulatory filings, Standard Offer PPAs and associated documents") again presents information that has not been introduced in the evidentiary record in these proceedings, and as a result, the Companies have had no opportunity to properly examine the information.

A third example arises in Section 4.4.1 of the Report, where Power Advisory introduces terms from an Avista Power PURPA tariff in Washington.[6] Finally, in Section 4.4.2, Power Advisory introduces Pacificorp's Standard form of PPA and relies upon terms and conditions in that PPA to inform its findings and conclusions regarding the Companies' proposed Notice of Commitment Form.[7] Each of these represents examples of Power Advisory, albeit likely unknowingly, introducing documents and other new information that is not in the evidentiary record, and then relying upon that information to inform its conclusions.

[4] Power Advisory Report, at 37.
[5] Power Advisory Report, at 37, fn. 115.
[6] Power Advisory Report, at 53, fn. 152.
[7] Power Advisory Report, at 55, fn. 159.

Because Act 62 provides for the third-party consultant to operate under the Commission's authority, not unlike a Commission employee, Power Advisory is prohibited under the Commission's ex parte standards, specifically S.C. Code Ann. § 58-3-260(C)(8)(b), from furnishing, augmenting, diminishing, or modifying the evidence in the record, and, as a result, the conclusions based upon this information should be disregarded and these references should not be relied upon by the Commission in its decision.

Moreover, Section 58-41-20(I) also expressly limits the Commission's review and consideration of Power Advisory's conclusions to those conclusions that are based on "evidence in the record." The documents and information discussed above were not introduced at the hearing as evidence, and therefore, were not subject to examination or objection, and are not part of the record of this proceeding. Accordingly, Act 62 also requires the Commission to disregard Power Advisory's conclusions that are improperly based upon information not included in the record.

B. The South Carolina Administrative Procedures Act, the Commission's Rules of Practice and Procedure, and the Companies' and other Parties' Right to Procedural Due Process Require that the Commission Disregard Conclusions not Based on the Evidentiary Record

In a contested proceeding, the South Carolina Administrative Procedures Act mandates that any information offered for inclusion into the record must be subject to objection and cross-examination and otherwise comply with the rules of evidence. *See* S.C. Code Ann. § 1-23-330. The Commission's rules of practice and procedure also require that any evidence offered for admission into the record "shall be subject to appropriate and timely objection." S.C. Code Regs. Ann. § 103-849. Assertions of fact and original analysis must be introduced in pre-filed testimony and exhibits and subject to cross-examination and discovery, in accordance with S.C. Code Regs. Ann. § 103-845. Accordingly, the Commission should dismiss any conclusions from the Power Advisory Report based on new information not entered into the evidentiary record.

The Companies similarly object to these conclusions of the Power Advisory Report on the basis that the introduction of new evidence not offered for admission into the record at the hearing, and therefore not properly subject to objection and cross-examination, violates the Companies' and other parties' procedural due process rights. Due process mandates that the parties have notice and an opportunity to be heard, and is protected by Article I, Section 22 of the South Carolina Constitution, which is applicable to administrative proceedings.[8]

In sum, the Companies recognize that the utilization of an independent third-party consultant, as provided for in Act 62, is a new process for the Commission and for Power Advisory. Duke's objections raised herein are founded in concern for the fundamental fairness afforded to all parties through statutes and regulations developed to preserve procedural due process. In furtherance of those protections, Act 62 is explicit that the Commission's reliance on the Power Advisory Report is limited to those conclusions reached "based on the evidence in the record." Accordingly, to the extent the conclusions in the Power Advisory Report rely upon new evidence not offered for admission into the record at the hearing, such conclusions should be disregarded by the Commission in its evaluation of the Power Advisory Report.

[8] The South Carolina Supreme Court has held that this provision applies the fundamental requirements of due process to administrative proceedings including, "notice, an opportunity to be heard in a meaningful way and judicial review." *Kurschner v. City of Camden Planning Comm'n*, 376 S.C. 165, 171, 656 S.E.2d 346, 350 (2008). Moreover, in a quasi-judicial or adjudicatory proceeding, "the substantial rights of the parties must be preserved." *Spartanburg v. Parris*, 251 S.C. 187, 190, 161 S.E.2d 228, 229 (1968).

III. Duke's Response to Discrete Power Advisory Report Findings and Recommendations

Sections 2 through 4 of the Power Advisory Report presents Power Advisory's evaluation of the record, independent analysis, findings, and conclusions. Duke provides responses to Power Advisory's findings and recommendations presented in the following sections of the Power Advisory Report.

Section 2.1 Defining Avoided Costs

Duke concurs in full.

Section 2.2 Perspective on Avoided Cost Risks

Duke generally accepts Power Advisory's comments as reasonable and reflective of the testimony before the Commission in these proceedings. Duke also does not dispute Power Advisory's comments that the addition of 4,000 MW of QF power has contributed to the reduction in avoided costs over time as well as affected the total $2.26 billion projected overpayment obligation that Duke has presented in these proceedings.[9] As Power Advisory recognizes, the impact of adding incremental solar on the current overpayment obligation has been a relatively small part of the approximately $30/MWh decline in avoided costs. As explained by Duke Witness Snider during the hearing, Duke's fundamental point remains valid that the focus of the risks to the using and consuming public in these proceedings result from longer-term administratively established avoided cost rates. (Tr. Vol. 1, p. 205-206.)

Duke also partially agrees with Power Advisory's statement that "the risk of overstating actual avoided costs . . . are mitigated by the direction in the Act that fixed price

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[9] Power Advisory Report, at 6.

obligations be based on a 10-year avoided cost determination."[10] Certainly, Duke's experience in North Carolina prior to 2017 shows that fixed price contracts over terms longer than 10 years impose significant overpayment risks on consumers. (Tr. Vol. 1, p. 46.13-14.) However, Duke's prior policy of fixing avoided cost rates and PPAs for larger QFs above 2 MW not eligible for the Standard Offer mitigated this risk of inaccurately projecting future avoided costs to an even more significant degree. (Tr. Vol. 1, p. 334.10.) Duke's prior policy of limiting price risk of longer term price risk also aligns with *Notice of Proposed Rulemaking on Qualifying Facility Rates and Requirements and Implementation Issues Under PURPA* ("PURPA NOPR"), recently issued by the Federal Energy Regulatory Commission ("FERC") on September 19, 2019.[11] (Tr. Vol. 2, p. 621.8.) Thus, the 10-year forecast of avoided costs required under Act 62 continues to present some overpayment risk, which increases as prices are fixed farther into the future. (Tr. Vol. 1, p. 205-206.) Duke also would highlight Figure 1 of the Power Advisory Report as representative of the increasing risks of fixing avoided energy costs over longer-term periods as the 10-year forward price of natural gas has declined by approximately 25% from 2015 to 2019. (Tr. Vol. 1, p. 58.25.)

Section 2.4 Transparency of Avoided Cost Filing

Power Advisory assessed the transparency of the Companies' Application and supporting testimony, commenting that "[Duke's] avoided cost filing and subsequent responses to data requests and requests for production of documents resulted in an avoided cost filing that was reasonably transparent."[12] As required by Act 62, the Report also

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[10] Power Advisory Report, at 6.
[11] *Implementation Issues Under the Public Utility Regulatory Policies Act of 1978*, 168 FERC ¶ 61,184 (Sept. 19, 2019) ("PURPA NOPR").
[12] Power Advisory Report, at 9.

identified that the Companies "provided a high level of cooperation and were responsive to Power Advisory requests."[13] Power Advisory also noted the compressed schedule of the proceeding, agreeing with ORS Witness Horii that "future proceedings would benefit from a more expanded period of time allowed for testimony and rebuttal testimonies."[14] Duke agrees. A more expanded proceeding could also allow Power Advisory, ORS, and other parties more time to assess the Companies' avoided cost filings and to become better informed of Duke's application of the peaker methodology to calculate avoided costs. For example, the sole transparency recommendation raised in the Power Advisory Report regarding the unit commitment modeling assumptions for Duke fleet resources used in the production cost simulation model ("PROSYM") to estimate the hourly avoided energy costs could have been better explained with additional time.[15]

Section 2.5 Avoided Energy Cost Estimates

The Report supports the Companies' use of the peaker methodology to estimate avoided costs, finding that the peaker methodology "is a widely accepted industry standard approach to quantifying avoided costs."[16]

Section 2.5.1 Negative Avoided Energy Costs

Section 2.5.1 of the Report summarizes SBA Witness Burgess's initial concerns with the prevalence of "negative" avoided cost hours experienced during typical solar production periods in PROSYM, and then summarizes portions of Duke Witness Snider's rebuttal testimony addressing this issue.[17] The Report then states that "[c]learly, these

[13] Power Advisory Report, at 4.
[14] Power Advisory Report, at 4.
[15] Power Advisory Report, at 10.
[16] Power Advisory Report, at 10.
[17] Power Advisory Report, at 11-13.

negative values significantly affect the avoided costs available to solar QFs."[18] However, this statement in the Report is not accurate. As Duke Witness Snider explained, the "negative" avoided cost hours are caused by adding 100 MW of no cost energy into PROSYM in the change case, which results in shifting generator startup times. Thus, the costs of the CT starts are not eliminated but are shifted from one hour to another, which can similarly occur during Duke's actual system operations as new generation is added. (Tr. Vol. 2, p. 630.20-23.) Witness Snider also pointed out that changes in the hours that the Jocassee and Bad Creek Pumped Hydro assets pump and discharge water can also result in negative hours between the Companies' base and change case in the production cost model. Again, this simply represents a shift in the system dispatch that has an overall positive avoided cost value even if certain hours viewed in isolation are negative. (Tr. Vol. 2, p. 630.23.) ORS Witness Horii agreed with Duke Witness Snider on this point during the hearing, explaining that the negative avoided cost hours are a function of shifting generator startup costs and "largely just nets out." (Tr. Vol. 2, p. 606-607.) Thus, it is important for the Commission to understand that the prevalence of individual hours with negative avoided costs identified by SBA Witness Burgess do not significantly affect the avoided costs available to solar QFs but reflect Duke's best estimate of the projected future operations of the DEC and DEP systems as QF generation is added.

Duke also questions the validity of the Power Advisory Report's statement that potential production cost savings from the operational flexibility provided by the dispatch down rights contractually provided under the Competitive Procurement of Renewable Energy ("CPRE") Program "have not been adequately acknowledged."[19] First, as

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[18] Power Advisory Report, at 13.
[19] Power Advisory Report, at 13.

recognized in the Report, purchasing power from QFs under PURPA does not provide Duke the same right to dispatch down rights to curtail solar QFs as provided for through CPRE. Duke Witness Holeman speaks to this extensively. (Tr. Vol. 2, p. 758.37-40). More fundamentally, however, it is important to recognize that Duke does not model a solar generator's operations in applying the peaker methodology to calculate avoided energy costs. As noted earlier in the Report, Duke's modeling assumes "the addition of a 100 MW generator available in all hours."[20] Because Duke applies a generic baseload 100 MW block of energy to calculate the avoided cost presented in this proceeding, it would not be appropriate to acknowledge the flexibility of CPRE solar resources as the comment in the Report seems to imply.

Section 2.5.3 DEP East and DEP West Integration

Power Advisory assessed Mr. Burgess's concerns with respect to how Duke's avoided cost analysis established a single avoided energy rate for DEP given the presence of two separate balancing authority areas. Having assessed Mr. Burgess's testimony, as well as Duke Witness Snider's rebuttal testimony on this issue, Power Advisory stated that it "believes that there is not an issue that needs to be remedied, recognizing that in this instance the Companies modeling reflects system conditions."[21] Duke agrees with Power Advisory's conclusion and continues to support application of a single avoided energy rate for DEP.

Section 2.5.4 Selection of Avoided Cost Periods

After undertaking independent analysis of Duke's projected hourly avoided costs, Power Advisory does not recommend any changes to the DEC or DEP avoided energy cost

[20] Power Advisory Report, at 13.
[21] Power Advisory Report, at 15.

rate periods.[22] Power Advisory recommends the Commission direct the Companies to provide appropriate analytical support for their avoided cost periods in subsequent filings. The Companies initially note that the nine avoided cost rate periods proposed by DEC and DEP in this proceeding are applicable to all QF technologies and are consistent with the avoided energy rate design recently approved by the North Carolina Utilities Commission in that Commission's recent *Notice of Decision* issued in that State's most recent biennial review of Duke's avoided costs. *See Notice of Decision*, N.C.U.C. Docket No. E-100, Sub 158 at 8 (Oct. 7, 2019) ("NC Notice of Decision") (*See* Finding Number 2 describing approved rate design as agreed to between Duke and North Carolina Public Staff).[23] If directed by the Commission, the Companies will provide additional analytical support for their avoided cost energy rate periods in the initial filing in the next biennial avoided cost proceeding initiated by the Commission.

Section 2.6 Large QF Avoided Cost Summary

Power Advisory stated that "calculating the rate at the time of the request, ensures that the avoided cost rate reflects current assumptions and avoids the risk of stale avoided costs, which can be more significant for a Large QF. Furthermore, the avoided cost rate will reflect the specific operating profile of the Large QF and result in a more reliable avoided cost rate."[24] Duke agrees with Power Advisory's proposal. As testified to by Duke Witness Glen Snider, Duke is only making two adjustments in the Companies' application of the peaker methodology to calculate avoided cost rates for Large QFs: (1) taking into account the production profile of the specific facility and (2) applying the

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[22] Power Advisory Report, at 17.
[23] The Commission took judicial notice of this North Carolina Utilities Commission Decision during the hearing. (Tr. Vol. 1, p. 15-17).
[24] Power Advisory Report, at 18.

most up-to-date inputs under the peaker methodology in order to more accurately align the avoided cost rates paid to the QF with the value provided to customers.

Section 2.7.1 Assessment of Avoided Capital Cost Methodology

Regarding the Companies' utilization of the peaker methodology to calculate avoided costs, Power Advisory stated that "given the Companies' proposed resource additions, Power Advisory believes that the peaker methodology is reasonable methodological basis for establishing the Companies' avoided costs."[25] Power Advisory additionally identified that SBA Witness Burgess similarly testified that "the general framework (i.e., the Peaker Methodology) is sound."[26] Duke agrees with Power Advisory's findings on this issue.

Section 2.7.2 Capital Cost of a New Peaker

The Power Advisory Report does not recommend any adjustment to Duke's CT capital cost used in quantifying avoided capacity value under the peaker methodology. This is consistent with ORS Witness Horii's testimony, finding Duke's avoided CT cost reasonable. (Tr. Vol. 2, p. 552.)

Power Advisory also evaluated and generally rejected SBA Witness Burgess's critiques of the CT cost Duke used in calculating avoided capacity value. In response to Mr. Burgess's recommendation that an aeroderivative peaker be used as the basis for the Companies' avoided capacity cost estimate,[27] Power Advisory found that "it would not be appropriate to base the solar resources' capacity payment on the aeroderivative peaker's

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[25] Power Advisory Report, at 19.
[26] Power Advisory Report, at 19.
[27] More precisely, Mr. Burgess recommended a significantly higher cost aeroderivative CT unit be taken into account but did not recommend that the Commission require Duke to solely rely upon the aeroderivative CT cost estimate. (Tr. Vol. 1, p. 382.58.) With this clarification, Mr. Burgess' recommendation should still be rejected.

capital cost because it isn't providing the same service."[28] Duke agrees with Power Advisory's conclusion that it is inappropriate to consider an aeroderivative CT's capital cost in calculating Duke's avoided capacity rates.

Power Advisory also evaluated the Companies' adjustment to the EIA CT cost to reflect the economies of scale associated with land, buildings, roads, security, gas interconnection, and other infrastructure for a 4-unit CT site. Based upon Power Advisory's review of the evidence presented during the hearing that 8 of DEC's and DEP's 11 power stations with CTs have 4 or more CTs, the Report states that Power Advisory "agrees with the Companies."[29]

In regards to Mr. Burgess's argument that the Companies should be required to include significant transmission upgrades costs to interconnect the CT to it transmission network, Power Advisory noted "that avoiding transmission upgrades can be an important driver of the location of new utility resources" and that "adding such a cost is likely to be speculative and inappropriate without additional evidence that such network upgrades are likely."[30] Duke agrees with Power Advisory that it is inappropriate to include a transmission network upgrade adder to the avoided capacity cost.

Duke also notes that the Power Advisory Report did not address Mr. Horii's recommendation to adjust the Fixed Charge Rate input to the peaker methodology, which Duke continues to believe is inappropriate.

[28] Power Advisory Report, at 19-20.
[29] Power Advisory Report, at 20.
[30] Power Advisory Report, at 20.

Section 2.7.3 Capacity Value Timing

In surrebuttal and at the hearing, Mr. Burgess took issue with the fact that the Companies did not include the accelerated retirements of Allen Units 4 & 5 and Cliffside 5 when calculating DEC's avoided capacity cost rates. Mr. Burgess argues this resulted in DEC underestimating the avoided capacity value of QFs. In response to Mr. Burgess, the Companies argued that there would likely be a more than offsetting reduction in avoided energy costs when accounting for these retirements, which would lower the overall avoided cost rate. (Tr. Vol. 1, p. 163-164.) Power Advisory states that this overall reduction in the avoided energy rate "may not be the case," and therefore recommends "that DEC's avoided capacity cost be adjusted to reflect a one-year acceleration of the year in which capacity is required" from 2026 to 2025.[31] In response, Duke continues to believe that DEC should not be required to accelerate its first identified year of capacity need (2026) prior to regulatory acceptance of these earlier unit retirement dates, which then would be incorporated into DEC's 2020 IRP. (Tr. Vol. 1, p. 156-157). Even if the Commission were to decide this first year of capacity need should be accelerated to account for these prospective earlier unit retirement dates, it would be wholly improper to only account for the early retirements when determining the Companies' avoided capacity costs and not when also determining the Companies' avoided energy cost. Second, as described by Witness Snider, it is appropriate, and a utility must at some point, select a specific point in time or "snap a chalk line" in determining its resource plan and calculating avoided cost rates. (Tr. Vol. 1, p. 156-157.) ORS Witness Horii also accepted this as a "reasonable" approach during the hearing. (Tr. Vol. 2, p. 550-551.) Therefore, Duke disputes Power

[31] Power Advisory Report, at 21.

Advisory's conclusion that Duke's avoided costs would be more accurately determined at this time by unilaterally moving DEC's first year of need from 2026 to 2025.

In addition, Power Advisory states that it "believes that reflecting capacity value after 2029 in the avoided capital cost estimates would violate the direction in Act 62 to 'reduce the risk placed on the using and consuming public.'"[32] Duke agrees.

Section 2.7.4 Weighting of Peak Periods

Pertaining to Duke's seasonal capacity allocation, the Report recognizes that "DEC and DEP are now primarily winter peaking for two main reasons: the growing penetration of solar capacity and volatility in winter peak demand."[33] Power Advisory goes on to note that intervenors disagreed with Duke's seasonal allocation proposal and put forth other proposals. In regard to Mr. Burgess's proposal, Power Advisory states first, that it "believes the LOLE studies used by Duke are an appropriate methodology to assess the seasonal contribution of capacity."[34] Therefore, Power Advisory finds that "the seasonal estimates put forth by Mr. Burgess using a simpler methodology should not be adopted." This aligns with Duke's position that Mr. Burgess's seasonal allocation proposal should not be adopted.

In regard to Mr. Horii's proposal, however, Power Advisory states that it "believes that the capacity weightings proposed by Mr. Horii in his Surrebuttal Testimony are reasonable and that the Companies should be directed to update their avoided capacity cost rates to reflect these weightings."[35] To explain, Mr. Horii proposed that the Companies rely upon "Tranche 1" solar penetration assumptions when calculating the Companies'

[32] Power Advisory Report, at 21.
[33] Power Advisory Report, at 22.
[34] Power Advisory Report, at 27.
[35] Power Advisory Report, at 27.

seasonal allocation. (Tr. Vol. 2, p. 528.8-9.) As explained by Duke Witness Snider, the "Tranche 4" assumptions represent the most appropriate data to use because Duke has a statutory obligation to procure this amount of capacity under the North Carolina CPRE Program and other regulatory mandates. Therefore, the "Tranche 4" data accurately reflects what capacity the Companies will ultimately have on the system throughout the term of the QF's PPA. Moreover, as further explained by Mr. Snider, accepting Mr. Horii's proposal could also result in a double payment to QFs. (Tr. Vol. 2, p. 630.49.) Therefore, while Duke finds ORS Witness Horii's position significantly more reasonable than SBA Witness Burgess's recommendation, Duke disagrees with Power Advisory's position and continues to support the Companies' seasonal allocation as proposed.

Duke also notes that the Power Advisory Report does not recognize that the recent NC Notice of Decision on Duke's North Carolina avoided costs adopted Duke's proposed seasonal allocation of capacity value. (*See NC Notice of Decision* Finding Number 3). The Commission took judicial notice of this recent assessment of Duke's avoided capacity and energy costs in North Carolina at the outset of the hearing. (Tr. Vol. 1, p. 15-17).

Section 3.2 Solar Integration Services Charge Settlement

In regard to the Solar Integration Services Charge Settlement, Power Advisory "accepts this settlement agreement as a reasonable accommodation among the parties regarding the contentious issues surrounding variable resource integration charges." Duke agrees.

Section 4.1.1 Implications of 10-year PPA Contract Length in South Carolina

In introducing this Section, the Report states "Act 62 represents a delicate balancing of the interests of the 'consuming public' and the interests of QFs, while 'striving to reduce the risk placed on the using and consuming public.'"[36] Duke agrees, and has provided extensive testimony in this proceeding attempting to frame the requirements of Act 62 within the context of PURPA. (*See George Brown Testimony,* at Tr. Vol. 1, p. 46.4-8, 12-17; Tr. Vol. 2, p. 621.26-35.)

The Report further suggests that, "Act 62 by no means establishes ensuring QF project development as a threshold."[37] Duke agrees, and has emphasized in testimony that the Commission has no meaningful ability to review the financeability of QFs as PURPA itself largely exempts QFs from Commission oversight of QF owners' profits and business operations. (Tr. Vol. 2, p. 621.38.) Accordingly, Duke Witness Brown has emphasized that there is no basis to conclude that PURPA requires all QFs to be able to obtain regularly available market rate financing, nor is the Commission required to undertake efforts to determine what avoided cost rates, terms and conditions would be "financeable" for QFs. (Tr. Vol. 2, p. 621.35-37.)

However, without identifying that Power Advisory considered Duke's evidence on this issue, the Report attempts to address "the implications of the proposed avoided costs on the resulting opportunities for QF development in South Carolina."[38] Following a cursory, two-page analysis, the Report concludes that, "without longer contract length, the solar industry would not be able to finance PURPA projects in South Carolina because they would not be economical."[39] Duke fundamentally disagrees with the focus of Power Advisory's analysis in this regard as well as the limited and improper analytical basis for its conclusions. As explained by Duke Witness George Brown, the Commission does not

[36] Power Advisory Report, at 33.
[37] Power Advisory Report, at 33.
[38] Power Advisory Report, at 34.
[39] Power Advisory Report, at 34.

have the authority under PURPA or Act 62 to investigate the QF industry's cost of development or the profits required by investors to make QF projects attractive investments. (Tr. Vol. 2, p. 621.37-38.) Moreover, Power Advisory does not cite to any testimony in the record where QF developers have represented that they are incapable of developing projects based upon Duke's current avoided cost rates and a 10-year term contract—in fact, while parties may have articulated a desire for longer term contracts, no party asserted that financing was impossible at 10 years. Furthermore, Power Advisory provides no meaningful evidence that solar projects are not able to attract financing under the proposed 10-year contracts, nor does it specify how lengthening the contract under the terms of Act 62 will make projects more financially viable. Act 62 requires that any contract approved by the Commission for longer than 10 years must include a "reduction in the contract price relative to the 10-year avoided cost." S.C. Code Ann. § 58-41-20(F)(1). Power Advisory does not explain or demonstrate how extending the contract overcomes what it sees as "[t]he problem" identified at page 34 of its Report, which is "the currently proposed avoided cost rates."[40] Even if the Commission were to accept that Duke's currently low avoided costs of energy and capacity are "the problem," the Report does not make clear how extending the contract at an even lower price will enable projects to be financed. Instead, the Report presents a high-level benchmarking analysis in Figure 4 relying on only two data points. By contrast, Witness Brown has provided evidence and analysis demonstrating that longer term contracts pose substantial overpayment risk to customers. (Tr. Vol. 1, p. 46.16.)

[40] Power Advisory Report, at 34.

To support its benchmarking analysis, Power Advisory first references a 2017 Georgia Power competitive bid process where that utility procured "510 MWs of solar in Georgia with an average price of $36/MWh for 30-year contracts."[41] As discussed in Section II, these facts and figures are not a part of this proceeding's evidentiary record. The press release cited by the Report also does not contain either the contract term or average pricing information referenced within the Report.[42] The only evidence in the record regarding the Georgia Power competitive solicitation program is that PPAs competitively solicited under that program were required to be below Georgia Power's avoided costs. (Tr. Vol 2, p. 700.) Moreover, there is no explanation in the Report or in the record of this proceeding of what non-PURPA contractual terms and requirements may apply to projects participating in the Georgia competitive solicitation program, such as whether enhanced dispatch and curtailment right are required similar to the North Carolina CPRE Program. (Tr. Vol. 1, p. 84.) Consideration of the specific contractual terms and conditions applicable to the competitive solicitation program could significantly affect the cost of projects bidding into the Georgia program versus selling under PURPA in South Carolina. The Report fails to recognize the staleness of the referenced 2017 Georgia PPAs in arriving at its unqualified conclusion that fixed price contract terms longer than 10 years are required to finance PURPA projects in South Carolina.

The Power Advisory Report also fails to identify evidence in the record that actually undercuts its assumption about the correlation between longer contract terms being required to finance QFs at Duke's current avoided costs. In fact, Duke Witness Brown testified that Duke has recently signed nine PPAs totaling 472 MW in North Carolina at

[41] Power Advisory Report, at 34.
[42] Power Advisory Report, at 34, fn. 109.

that State's maximum five year contract terms for administratively set PURPA rates. (Tr. Vol. 2, p. 621.34.) The exclusion of this evidence in Power Advisory's analysis leads to the unsupported conclusion articulated above.[43] While admittedly not in the record of this proceeding, and not to be relied upon in the Commission's ultimate decision, Duke has also executed two additional five-year fixed price PPAs since Duke Witness Brown filed rebuttal testimony on October 2, 2019. The capacity weighted average price of these eleven now-executed five-year PPAs is $36.90/MWh, which is well below the "illustrative" range of PPA pricing required to secure financing identified in Figure 4 of Report under 10 year contracts. Put another way, the five-year contracts actually being executed by solar developers today are priced well below what Power Advisory's analysis represents to be the minimum "PPA price to secure financing (illustrative)" which Figure 4 identifies as $40. This disparity calls into question the accuracy of Power Advisory's exhibit and its entire thesis. Further, Power Advisory's reference to a 2017 Georgia Power competitive solicitation (and citation to a Georgia Power press release) also fails to identify that Georgia Power has undertaken a more recent 2019 utility-scale solar competitive solicitation and, in October 2019, announced that Georgia Power had contracted with three additional solar projects totaling 540 MW at an average price of $34/MWh over 30 year PPA terms.[44] Again, this information is not in the record of this proceeding, and should not be relied upon by the Commission in its ultimate decision. However, it is surprising that Power Advisory has asserted such definitive conclusions based upon such limited information

[43] If the Commission accepts the citations and analysis from Power Advisory that Duke argues should be disregarded, a fuller reference to contracts outside of South Carolina should be allowed.
[44] Georgia Power Company's Application for the Certification of the 2020/2021 Renewable Energy Development Initiative Utility Scale Power Purchase Agreements, at 9, Ga. P.S.C. Docket No. 42625 (filed Oct. 3, 2019).

about Georgia's competitive solicitation program, especially information that is not up to date.

The Companies also note that Power Advisory's second benchmarking data point—the average pricing for 550 MW of solar procured in CPRE Tranche 1—fails to recognize record evidence in this proceeding that the utilities and customers receive additional benefits in terms of enhanced dispatch and curtailment rights and environmental attributes under this North Carolina competitive solicitation program that are in excess of the requirements under PURPA. (Tr. Vol. 1, p. 83-84.) These enhanced 10% (DEP) and 5% (DEC) dispatch rights directly impact the economics of projects bidding into the CPRE Program as Duke's system operators have the contractual rights to fully curtail CPRE projects for up 876 hours (DEP) and 438 hours (DEC) per year. (Tr. Vol. 2, p. 758.45.) Therefore, this data point also does not support Power Advisory's conclusion that solar QFs selling under the commercially reasonable Standard Offer PPA and Large QF PPA approved by the Commission in these proceedings will not be financeable. In addition, these CPRE projects have conveyed the renewable energy attributes (also known as Renewable Energy Certificates or RECs) to Duke via the CPRE contracts while PURPA contracts do not convey those attributes. As explained by Duke Witness Brown, the Companies can use the RECs to meet compliance obligations or can sell them in the market and use the sales proceeds to reduce the PPA expense to customers. (Tr. Vol. 1, p. 79-81, 211.) Thus, it is inaccurate to compare the CPRE average rate to the avoided cost rate because of the different contract terms between CPRE and PURPA avoided cost contracts.

Finally, Section 4.1.1 of the Power Advisory Report identifies other considerations and potential "investor concerns" regarding the 10-year contract length. Duke initially notes that the Power Advisory Report fails to consider record evidence about significant recent declines in solar PV development costs—EIA has reported a 67 percent decline between 2013 and 2017—and other consideration that can impact the development of solar generation. (Tr. Vol. 2, p. 621.34.) Duke does not believe these considerations support the Commission extending the contract tenor offered beyond 10 years in these proceedings.

In summary, Duke does not find Power Advisory's high-level benchmarking analysis to be accurate, and believes the Commission should not find it persuasive. More importantly, it would be inappropriate for the Commission to rely upon this analysis as it is derived from information not in the evidentiary record in these proceedings. As stated by Duke Witness George Brown during the hearing, Duke's position remains that independently-administered competitive solicitation processes, like those approved in North Carolina and Georgia, provide a less risky and more cost-effective way to procure new solar capacity for customers. (Tr. Vol. 2, p. 621.24.)

Section 4.1.2 Risk Mitigation

This section of the Power Advisory Report addresses potential risk mitigation strategies for longer term PPAs, identifying the potential to "mitigate the risk to the investors in the post-PPA period would be to have some sort of upper and lower price bounds" as generally testified to by SBA Witness Levitas during the hearing.[45] Duke agrees with Power Advisory's conclusion that such a concept would "defeat the purpose of ensuring up to date rates for the ratepayers as the rates and guaranteed price range might

[45] Power Advisory Report, at 36.

not overlap."[46] Duke also agrees with Power Advisory that Intervenors have not proposed longer-term PPA options as allowed under S.C. Code. Ann. § 58-41-20(F)(1).[47]

Section 4.1.3 Comparison with PURPA Contract Lengths in Other States

This is another section where Power Advisory introduces significant new facts and documents that are not in the evidentiary record. Because this information was not entered into the record, Duke's opportunity to evaluate the accuracy of the Report's characterization of the PURPA frameworks in all 15 states identified in the Report has been limited. This challenge is exacerbated by the fact that in citing to the underlying basis for the information in Figure 5, Power Advisory cites only to "Power Advisory, based on various regulatory filings, Standard Offer PPAs and associated documents" to support the details of its analysis.[48] Duke initially notes that the record evidence in this proceeding disputes Power Advisory's conclusion that Idaho's two year contract term is "the shortest PURPA PPA contract length in the US" as Southeastern States including Alabama Mississippi and Tennessee each offer various forms of one-year term with evergreen provisions allowing QFs to sell power in future years at updated avoided cost rates. (Tr. Vol. 2, p. 621.25-26.) Duke's evidence that the proposed fixed 10-year fixed avoided cost rates required under Act 62 will be the longest fixed rates offered under PURPA in the Southeast for projects larger than one MW also remains uncontroverted. (Tr. Vol. 2, p. 621.25.)

Power Advisory also fails to address a critically important point in terms of its presentation of this information about PURPA contract length in other States. Specifically,

[46] Power Advisory Report, at 36.
[47] Power Advisory Report, at 36.
[48] Power Advisory Report, at 37.

the Report does not identify what size QF is eligible for the longer-term contracts being approved by other State Commissions under PURPA. Record evidence in this proceeding shows that Figure 5's reference to North Carolina's term declining from 15 years to 10 years is limited only to North Carolina Standard Offer projects one MW or less. QF projects larger than one MW in North Carolina have the options of a fixed price five-year term or to participate in the CPRE Program. (Tr. Vol. 2, p. 621.25.) Similarly, while not in the record in this proceeding, Power Advisory's comments that Washington state and other western jurisdictions offer contract terms of 15-20 years are limited to their Standard Offer rates and to QFs of a maximum size of five MW or less. In contrast, Act 62 prescribes that Duke must offer 10-year fixed price contracts to all small power producer QFs up to 80 MW in size. S.C. Code Ann. § 58-41-20(F)(1). This is fundamentally different than prescribing longer-term Standard Offers in the other jurisdictions identified in Figure 5 of the Report and would impose significantly greater risks on Duke's customers.

Section 4.2.1 Material Alterations – Retroactive vs. Prospective

Power Advisory's Report questions whether Duke would identify existing operating projects that have made changes in the past that are now deemed Material Alterations and as a result, terminate the PPA.[49] Power Advisory additionally questions whether Duke is referring to the Material Alteration terms/conditions only or all terms/conditions that are being revised in the Standard Offer as part of this proceeding.[50] Duke first notes that the addition of "Material Alteration" concept is to incent QFs to proactively notify Duke prior to making any material changes to its facility, not to prematurely terminate QF's PPAs. Second, in response to Power Advisory's question,

[49] Power Advisory Report, at 44.
[50] Power Advisory Report, at 44.

Duke's intent in proposing this clarified material alteration provision is not to proactively review purchases from existing QF Sellers to "catch" such Sellers deviating from their contractual commitment. Moreover, in regard to Power Advisory's second question, the Companies clarify that DEC and DEP are not proposing to retroactively amend existing Sellers' PPAs; instead, Duke is seeking Commission approval to amend the Schedule PP Tariff and Terms and Conditions applicable to all QFs, similar all other tariffed services authorized by the Commission. Duke does, however, continue to support the application of the "Material Alteration" provision to all QF's Schedule PP and Terms and Conditions, whether those QFs have previously contracted to sell power to Duke under a Standard Offer PPA or commit to do so in the future. As stated by Duke Witness Wheeler, the "proposed modification" merely "clarifies the contractual commitment between the parties." (Tr. Vol. 1, p. 260.13.)

Section 4.2.2 30-month In-service Date Following Rates Approval

In regard to the Companies' 30-month commercial operation date ("COD") provisions and Mr. Levitas's proposal to delete the same, Power Advisory agrees with Mr. Levitas, and explains that "it's only fair that the QF be given day-for-day extensions on its in-service date for any delays attributable to the in-service date of these interconnection facilities."[51] This reference to a "day-by-day extension" for delays leads the Companies to believe that Power Advisory may not recognize the distinction between (a) Mr. Levitas's proposal here, which is to tie the COD to the date on which interconnection facilities and network upgrades are constructed, and (b) other proposals by Mr. Levitas related to the COD, which extend the COD to the extent the utility is delayed in constructing or

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[51] Power Advisory Report, at 45.

delivering interconnection facilities and network upgrades. As the record reflects, the proposal Mr. Levitas put forward—to delete the 30-month COD provision and tie the COD to the date that interconnection facilities and network upgrades are constructed – would go much further than merely providing a "day-for-day extension on the in-service date," but instead would significantly extend the time period by which the QF must deliver power – from 30 months after the Commission's order to an entirely indefinite date that may be many years in the future. (Tr. Vol. 1, p. 263.) Given the testimony in the record that the interconnection process can take several years (Tr. Vol. 1, p. 282.34), Mr. Levitas's proposal would allow QFs to enter into the Standard Offer PPA at any time (no restrictions exists on when a QF may enter into a Standard Offer PPA), and wait several years until interconnection facilities and network upgrades are complete before the 10-year term on the PPA begins to run. Power Advisory correctly notes that Duke agreed to adopt this flexible COD for the Large QF PPA, but Duke coupled this change with adequate protections from customers by requiring that QFs have returned an executed Facilities Study Report prior to entering into the Large QF PPA, as explained by Duke Witness Johnson. (Tr. Vol. 1, p. 284.11.) It seems that Power Advisory may not appreciate the significance of the pairing these changes together. Accordingly, the Companies continue to support the inclusion of the 30-month COD set forth in the Standard Offer Tariff.

Section 4.3.1 Facilities Study Agreement (FAS) a Condition of Signing Large QF PPA

Power Advisory's Report opines that "Mr. Johnson has not addressed Mr. Levitas's point that the utility can potentially control or frustrate the QF if the QF has not received a System Impact Study within one year from the time of the Interconnection Request since the QF will not know its interconnection costs, albeit preliminary, before LEO formation."[52] Power Advisory's opinion that Duke should be required to deliver a System Impact Study within one year, however, fails to recognize Duke Witness Johnson's testimony that the South Carolina Generator Interconnection Procedures effectively prohibit the Companies from studying Interconnection Requests except for those designated as "Project A" and "Project B," and that the Companies must follow a serial process in evaluating Interconnection Requests. As Duke Witness Johnson further explained, this mandated serial interconnection study process, in addition to solar QFs requesting to interconnect to the same distribution and transmission areas by their choice, has resulted in hundreds of solar QFs being "interdependent" with another. (Tr. Vol. 1, p. 282.35.) Accordingly, due to the significant volume of solar generators requesting interconnection, it is often impossible for the Companies to deliver a System Impact Study within one year under the existing SCGIP. Moreover, the concept of a "mutually agreeable" timeframe for the System Impact Study fails to recognize Witness Johnson's testimony regarding FERC-jurisdictional Interconnection Requests' rights to "suspend" their Interconnection Request for a period of three years. (Tr. Vol. 1, p. 282.35.) While many complicated factors contribute to the Companies' inability to predict when a System Impact Study can be completed, the option for FERC Interconnection Requests to suspend illustrates this point rather succinctly.

Section 4.3.2 Offramp Should Interconnection Facilities & Network Upgrades Exceed $75,000/MW

The Companies' comments to Section 4.3.1 above are incorporated in Duke's response to Report Section 4.3.2, with regard to the challenges the Companies' face to provide a System Impact Study within a designated time period for all QFs from the date

[52] Power Advisory Report, at 47.

of Interconnection Request. Power Advisory's Report concludes that the "risk" to QFs of incurring liquidated damages because their interconnection costs make the project unviable is "unreasonable."[53] However, the Report fails to appreciate PURPA's requirement that the QF make an "unequivocal commitment" to sell its output to the Companies when entering into a PPA or non-contractual legally enforceable obligation ("LEO"). The Report also fails to take into consideration Witness Johnson's testimony citing to precedential case law, in which FERC recognizes that the generator development process is laden with risks. As Witness Johnson's testimony explained, FERC has stated that, "[w]hile [FERC] fully recognize[s] the value of regulatory certainty for financing new projects, business risks and a degree of uncertainty are always present when an entity proposes to construct a new generating facility and connect it to the grid." (Tr. Vol. 1, p. 284.25.) Duke therefore rejects Power Advisory's recommendation to provide a System Impact Report within one year or allow an offramp to the QF as infeasible and unreasonable recommendations that is inconsistent with PURPA's requirements that QFs make a binding and substantial commitment to establish a LEO. (Tr. Vol. 1, p, 282.11-12).

Section 4.3.3 Surety Bonds as a Permissible form of Performance Assurance

The Companies agree with Power Advisory's analysis that Duke's allowance of three performance assurance offerings is sufficient and that it is within Duke's discretion to determine the appropriate security for performance assurance.

[53] Power Advisory Report, at 48-49.

Section 4.4.1 All Required Permits and Land-use Approvals a Condition of LEO Formation

Acknowledging that both Witness Johnson and Witness Levitas offer good arguments in favor and against the requirement to secure permits and land-use approvals as a condition of LEO formation, Power Advisory concludes that, in balancing the concessions of SCSBA and the Companies, that QFs should be allowed to secure permits after LEO formation.[54] The Companies disagree with this conclusion and reiterate Duke Witness Johnson's testimony that this is a reasonable requirement that demonstrates a QF's commitment to develop its project, and is evidence of the project's viability. This is another section where Power Advisory introduces new documents that are not in the evidentiary record.

Section 4.4.2 365 Day In-service Requirement Following LEO Formation

Power Advisory concludes that the requirement for a QF to be in service within 365 days should be extended, as proposed by Witness Levitas, to account for any delays in the construction of Network Upgrades or Interconnection Facilities.[55] The Companies disagree with this conclusion and continue to support the 365 day in-service date as reasonable, as set forth in Witness Johnson's rebuttal testimony. (Tr, Vol. 1, p. 284.25-26.)

Section 4.4.3 Offramp Should Interconnection Facilities & Network Upgrades Exceed $75,000/MW

See Duke's response to Section 4.3.2 of the Power Advisory Report.

[54] Power Advisory Report, at 53.
[55] Power Advisory Report, at 55.

IV. CONCLUSION

Wherefore, Duke Energy Carolinas, LLC and Duke Energy Progress, LLC respectfully request that the Commission consider these comments in response to the Power Advisory Report in making its determination on the issues in dispute to this proceeding.

Respectfully submitted, this the 8th day of November 2019.

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